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Projections of Northern Great Plains Coal Mining and Energy Conversion Development 1975 - 2000 A.D.

By the MONTANA UNIVERSITY COAL DEMAND STUDY TEAM

Summary Volume

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MONTANA UNIVERSITY COAL DEMAND STUDY

Summary

Projections of Northern Great Plains Coal Mining and Energy Conversion Development 1975 - 2000 A.D.

by

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1. INTRODUCTION

Massive deposits of medium to low sulfur strippable coal underlie much of eastern Montana, northeastern Wyoming and western North Dakota--the Northern Great Plains states (NGP). Relatively strict sulfur oxide air pollution standards for coal-fired power plants have renewed interest in strip mining and its rapid expansion in the NGP states. Recent changes in international oil and natural gas markets and a growing concern about the eventual depletion of oil and natural gas reserves have created a rising interest on the part of both the federal government and the "energy industry" in further coal development in this region. This could lead to a massive coal boom that would drastically change the physical, social, and economic character of the NGP. What the actual level of coal development in the Northern Great Plains is "likely" to be is the subject of the Montana University Coal Demand Study, a four-part multi-volume study summarized here.[1] Such information becomes crucial if decisionmakers in the public and private sectors are to make preparations and adjustments appropriate to the level of coal development.

Many other researchers from energy companies, universities, and government agencies have already dealt with the question of the likely level of coal development on the NGP. They have all offered their best, reasoned guesses for the future. The problem with most of these studies is that little or no formal, analytical methodology stands behind them. As economic, technological, and political conditions change, one has no way of knowing whether these projections are based on contradicted assumptions and therefore rendered

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[1]See the Montana University Coal Demand Study, Final Report, pages ii - vi for a description of the entire study.

seriously inaccurate or useless. Unless the assumptions used in the projections and the sensitivity of the projections to those assumptions are clearly defined, the utility and reliability of the projections are questionable.

The Montana University Coal Demand Study is not just another set of projections of NGP coal development although it contains such projections. The Montana University Coal Demand Study attempts to do three things:

1. Present a systematic way to evaluate what will influence NGP coal development;
2. Indicate the key "swing" variables determining development; and
3. Establish how, quantitatively, the level of development will vary if these variables change.

The result, we hope, is a projection that should remain true even through future changes in political or economic conditions, for such changes will simply shift the projection in a quantitatively specified way to different levels. It should be noted at the outset that this Study is a first, fairly limited attempt to meet the above objectives. We have not studied all the individual determinants of the demand for NGP coal in equal depth. Throughout we have tried to indicate both the Study's limitations and the research that further refinement would require.

In the following report, two primary sources of demand for NGP coal are analyzed--coal-fired electric generation and gasification of coal into synthetic natural gas. A variety of projections are presented, each dependent upon a particular set of assumptions. These projections are compared with each other and with previous projections--in particular those made by the Northern Great Plains Resources Program and the Federal Energy Administration's Project Independence Report. Finally, the differences among the various projections are critically analyzed.

2. CONCLUSIONS

The following conclusions are drawn from the Montana University Coal Demand Study (MUCDS).

1. The demand for Northern Great Plains (NGP) coal is very sensitive to air pollution control regulations. If federal and state air pollution emission regulations require flue gas desulfurization (FGD) and/or low sulfur coal for both new and existing coal-fired electric generating plants, NGP coal will be competitively priced in a 21-state market. If Supplementary Control Systems (SCS) such as tall stacks and/or intermittent control systems are permitted in place of FGD, NGP coal will be competitive in a much smaller 13-state market, eliminating much of the midwest and south-central regions of the U.S.

2. Current contracts for NGP coal indicate that the electric power industry expects FGD to be required on all coal-fired plants. If FGD is not required, the demand for NGP coal will not approach the levels indicated by current contracts (136 million tons/year) in the 1980-85 period and probably would not reach those levels by the year 2000.

3. Very large scale (>500 million tons per year) coal development in the NGP will be possible by the year 2000 only in the unlikely event that:

   a. Historic rates of growth in electric consumption continue. This in turn will be possible only if real electric prices decline over the next decade.

   b. Rapid and extensive conversion of coal to synthetic natural gas and/or synthetic liquid hydrocarbons, petrochemicals, and fertilizers takes place.

4. The most "likely" level of NGP coal development is 136 million tons/year by 1980, 140-170 million tons/year by 1985, and 200-300 million tons/year

by the year 2000. For comparison, in 1975 the projected level of mining was 52 million tons.[2]

5. An analysis of current and foreseeable economic and technological conditions indicates that coal gasification industry is not viable unless it is heavily subsidized.

6. Price-sensitive econometric projections indicate that the future growth in electric power consumption will not follow historic trends. These models project annual growth in electric power consumption in the range 1%-5%, as opposed to the historic growth rate of 7%-8% per year over the past two decades.

7. Extremely rapid growth in nuclear-fueled generation appears very doubtful. We project a considerably slower rate of development, but one which still may be too high.

8. Insufficient information exists to make even reasonable guesses about the possible level of NGP coal production for coal liquefaction, petrochemical, or fertilizer production.

9. The Northern Great Plains Resources Program's (NGPRP) "intermediate" projections of NGP coal development for electric generation are similar to our "most likely" projections, but this similarity probably results from several offsetting errors in the NGPRP analysis.

10. The NGPRP coal gasification projections are probably too high because of inappropriate or currently outdated assumptions.

11. The Project Independence Report projects unreasonably low levels of coal export from the NGP which are likely only if sulfur oxide air pollution control regulations are dramatically weakened.

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[2]NGPRP Summary Report, Effects of Coal Development in Northern Great Plains, (April, 1975), p. 26. The "intermediate development profile."

3. METHODOLOGY

There are two primary sources of demand for NGP coal: one is a reality now, the other is a looming potential. Electric utilities now consume 60%-70% of the nation's coal[3], and almost 100% of the NGP coal now under contract. Another major potential demand for NGP coal is gasification to produce synthetic natural gas (SNG). These two sources of demand are analyzed and projected separately, although it would be more accuarate to explicitly deal with the fact that coal-fired generation of electricity can substitute for gaseous fuels, whether natural or synthetic.

A final source of potential demand for Northern Great Plains coal--liquefaction, petrochemicals, and fertilizer production--was not analyzed in this study. There simply were not enough technical and economic data available to permit a convincing analysis of the potential applicability of these processes to NGP coal resources. At this time we can only suggest that there is a potentially significant demand for NGP coal as a feedstock for these coal conversion technologies, particularly beyond 1985. If these technologies do prove economically feasible, the demand for NGP coal will be larger than that reported here.

Figure 1 outlines the analysis used in this project. In order to project the "likely" level of demand for NGP coal for coal-fired electric generation we followed four steps. First, we sought to define that geographic area where NGP coal could compete successfully with the coal of other regions, particularly the midwest, in supplying electric utilities. We analyzed the costs faced by utilities using the coal from different regions and derived a market boundary within which NGP had an advantage over the coal of other regions. The pollution

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[3]Federal Energy Administration, Project Independence Report (November, 1974, p. 289.

FIGURE 1

Outline of Methodology and Key Variables

I. How much NGP coal will be used for coal-fired electric generation?

A. Over what geographic area (market) can NGP coal be competitively sold?

1. What is the price of coal at the mine mouth in various regions?
2. What transportation costs are involved in delivering coal from particular regions to the site where it will be used?
3. What special handling costs are associated with the use of a particular region's coal?
*4. What pollution control costs are associated with use of a particular region's coal?

B. How rapidly will the consumption of electricity grow in that market area?

*1. At a particular constant annual rate of growth, or
*2. At a variable rate influenced by particular rates of change in energy prices?

C. How much of this electricity will be generated by burning coal?

*1. That residual left after assumed rates of growth of nuclear and hydroelectric generation facilities are projected, or
2. That share which currently (1973) is coal-fired in the market area?

D. How much of this coal will come from the NGP?

1. All coal needed within the NGP coal market area,
2. All that needed by new coal-fired generation in the market area, or
3. A share similar to that which current contracts indicate will be purchased from the NGP in 1980?

II. How much NGP coal will be used to produce synthetic natural gas?

A. What will it cost to gasify coal into pipeline quality gas?

B. What will the value of that gas be?

*1. What are the costs and availability of fuels which are competing substitutes for SNG?
*a. Natural gas
b. Coal in industrial uses
c. Electricity, coal-fired.

C. How will demand for gaseous fuels respond to much higher fuel prices?

D. How will governmental policy affect the fuel choice decision?

*1. Continued regulations of natural gas production?
*2. Subsidization of SNG plants?

---

*Key variable or assumption.

control cost associated with burning high sulfur coal from other regions was the key "swing" variable in this market definition.

Secondly, we estimated the future level of consumption of electricity from the NGP market area using two different approaches. One approach analyzed the impact of rising electric and natural gas prices on electricity consumption, while the other simply projected constant rates of growth.

Third, we tried to estimate what part of this projected electric production would be produced by burning coal (as opposed to nuclear, hydro-electric, or gas-fired electric generation). Here again we used two approaches. One was to analyze the potential for nuclear and hydroelectric generation, and to predict their future growth based on technology, politics, and economics of these generating methods. This left coal-fired generation as a residual. The other method was to see what combination of coal hydroelectric, and nuclear-fueled generation currently exists in the NGP coal market area and assume this fuel mix would remain constant until the year 2000. Our analysis of this "fuel mix" is the weakest point, particularly since the assumption made about the growth of nuclear facilities is crucial.

The final step in our projection was to estimate how much of this demand for coal for electric generation would come from the NGP states as opposed to other areas. Three alternate approaches were considered here: (1) The NGP would supply <u>all</u> coal used for electric generation within the market area; (2) the NGP would provide the coal for all <u>new</u> coal-fired generators; or (3) the mix of NGP coal and coal from other sources implicit in electric utility contracts to buy coal in 1980 would not vary beyond that date. These alternate assumptions gave us the demand for NGP coal for use in electric generation.

Another important (potential) source of demand for NGP coal is gasification to produce pipeline-quality synthetic gas fuel (SNG). In estimating the demand for NGP coal for this use, we studied the likely cost of producing such SNG as well as the value of SNG once produced. These were then compared to indicate the economic rationality of such production. In addition, we considered likely governmental policies which might influence production regardless of economic rationality.

In order to analyze whether coal gasification is economically viable, we had to first consider whether there are low cost substitutes for SNG. If expanded natural gas supplies, coal for industrial use, or coal-fired electric generation for commercial and domestic uses are adequate substitutes for SNG and can be made available at a lower cost than SNG, the demand for coal for SNG production disappears. However, the elimination of the demand for NGP coal as a feedstock for SNG may create a demand for the direct combustion of NGP coal as a boiler fuel or for increased electricity, which may be NGP coal-fired. In any case, gasification of coal into synthetic natural gas is likely to be an economic decision which depends on political and regulatory policy. Government policy combined with energy company decisions could restrict the supply of natural gas so severely that SNG might become viable. Similarly, the government could subsidize SNG plants which were not viable in market terms, thus overriding the financial constraints which would otherwise block private development.

4. ELECTRIC ENERGY DEMAND AND THE DEMAND FOR NGP COAL

As discussed previously, our method used four steps to estimate the demand for NGP coal for coal-fired electric generation. In this section each is discussed individually.

4.1 The Market for NGP Coal for Coal-Fired Generation.

The first step in delineating the geographic area in which NGP coal had a cost advantage was to assume that NGP coal was all mined at a "point source" in northeastern Wyoming. The cost of using this source of NGP coal was then compared to the costs of using "midwestern" coal located at a "point source" in central Illinois. Most of the "costs" of using various types of coal are straight-forward, and our analysis indicated that the line (hypercircle) defining the market in which NGP coal had a cost advantage was not very sensitive to them. These variables included the cost of (1) mining coal; (2) additional construction necessary to increase boiler size and construct the larger coal handling and pulverizing facilities due to the low BTU value of NGP coal. We determined that flue gas desulfurization required by federal New Stationary Source Performance Standards for plants burning midwestern high-sulfur coals is the most important cost variable. Thus, the sulfur oxide air pollution standards actually enforced are very important in determining the market open to NGP coal. If flue gas desulfurization for midwestern coal is not required, and for instance, tall stacks or intermittent control measures are permitted, midwestern coal costs are dramatically reduced and can compete to remove a good part of the midwestern market from NGP coal.

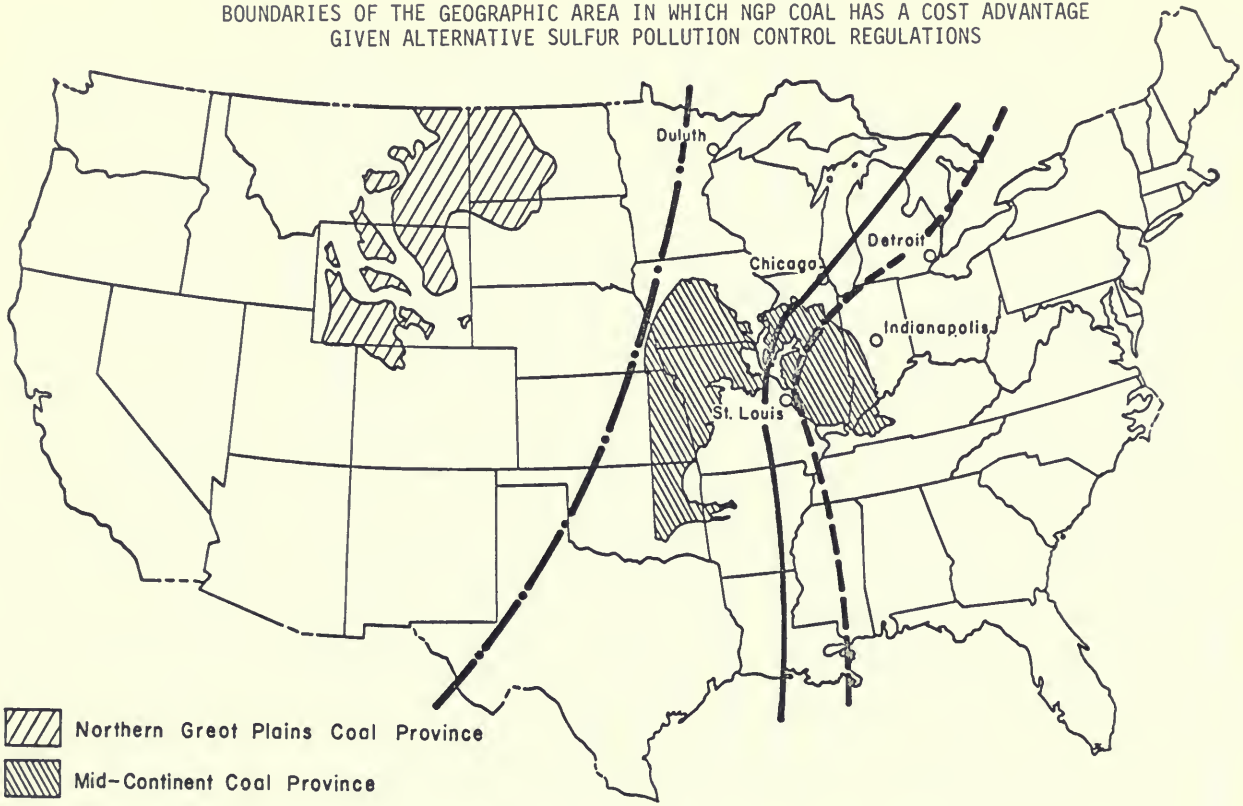
Figure 2 demonstrates the impact of various pollution standards on the geographic area in which NGP coal has a cost advantage (the "market" for NGP coal). In defining this market, we focused primarily on federal emission standards, assuming that:

1. State air pollution standards as strict as federal standards would prevail because of nearly total agreement between state and federal standards in the eight critical "swing" states in the NGP coal market area;

2. There are sufficient low pollution areas so that federal ambient air pollution standards will not restrict coal-fired generation; and

FIGURE 2

BOUNDARIES OF THE GEOGRAPHIC AREA IN WHICH NGP COAL HAS A COST ADVANTAGE GIVEN ALTERNATIVE SULFUR POLLUTION CONTROL REGULATIONS


Duluth
Detroit
Chicago
Indianapolis
St. Louis
Northern Great Plains Coal Province
Mid-Continent Coal Province
Supplementary Control Systems Permitted on all Coal Fired Power Plants.
Flue Gas Desulfurization Required on all New Coal-Fired Plants.
Flue Gas Desulfurization Required on all Coal-Fired Plants.

3. There is sufficient NGP coal with a sulfur content low enough to be burned without flue gas desulfurization and not violate the federal New Stationary Source Performance Standards.

Figure 2 indicates that (1) if supplemental control systems are permitted on all coal-fired power plants, the market for NGP coal shrinks into western Minnesota and western Texas as the cost of midwestern coal falls; (2) if scrubbers are only required on new coal-fired plants, the market for NGP coal includes only western Wisconsin and parts of Michigan, Illinois, and Louisiana; and (3) if flue gas desulfurization is required for all plants, new and old, using midwestern coal, the market for NGP coal extends into Michigan, Illinois, and Mississippi.

Our calculations indicated that these market definition lines are not very sensitive to either alternative transportation costs or relative pricing of alternative coal supplies.

This market analysis resulted in three alternative markets. One, an "All FGD" market, assumes flue gas desulfurization is required on all coal-fired plants. It includes the following 21 states: Montana, Wyoming, Washington, Oregon, Idaho, Colorado, Iowa, South Dakota, North Dakota, Minnesota, Nebraska, Illinois, Missouri, Wisconsin, Arkansas, Louisiana, Kansas, Oklahoma, Texas, Indiana, and Michigan. Another smaller market, our "All SCS" market, assumes that supplementary control systems (SCS) are acceptable on all plants. The All SCS market includes only 13 states, dropping Illinois, Missouri, Wisconsin, Arkansas, Louisiana, Indiana, and Michigan. In our "Partial FGD" market estimates we assume that all new plants require scrubbers, but existing plants are allowed to use SCS.

Our compilation of existing NGP coal contracts to 1980 by state of destination[4] indicates a market that coincides with our 21-state All FGD market area with the exception of the state of Washington. The latter should clearly be included in the market area given the current proposals for mine-mouth plants to transmit energy to the Pacific Northwest. This evidence suggests that utilities, despite their lobbying against mandatory use of scrubbers, expect scrubbers rather than supplementary control systems to be required and are making plans on that basis.

Figures 3A and 3B indicate the impact of these market-defining assumptions about pollution control requirements on the demand for NGP coal for coal-fired electric generation, for a "reasonable" set of assumptions. Figure 3A shows the effects of a "moderate" (3%) rate of growth in electric consumption, and Figure 3B does the same for a higher (5%) rate of growth. The 1980 result is based on the minimum coal tonnage indicated by existing contracts. Note that demand for NGP coal in 1985 will be lower than current contracts unless flue gas desulfurization is required on all coal-fired plants. Permitting supplementary control system on existing plants, but requiring FGD on new plants, still decreases the demand for NGP coal to levels below existing contracts. Again, electric utilities clearly assume that FGD will be required on all coal-fired plants.

4.2 The Demand for Electricity in the NGP Coal Market Area

After defining the area in which NGP coal will be sold, we turn to the demand in that area for electricity (and, ultimately, the demand for the coal to generate that electricity).

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[4]Table 20 in MUCDS Final Report and MUCDS Working Paper No. 4.

FIGURE 3A

THE EFFECT OF DIFFERENT POLLUTION CONTROL REQUIREMENTS ON DEMAND FOR NGP COAL FOR ELECTRIC GENERATION (3% annual growth in electric consumption)

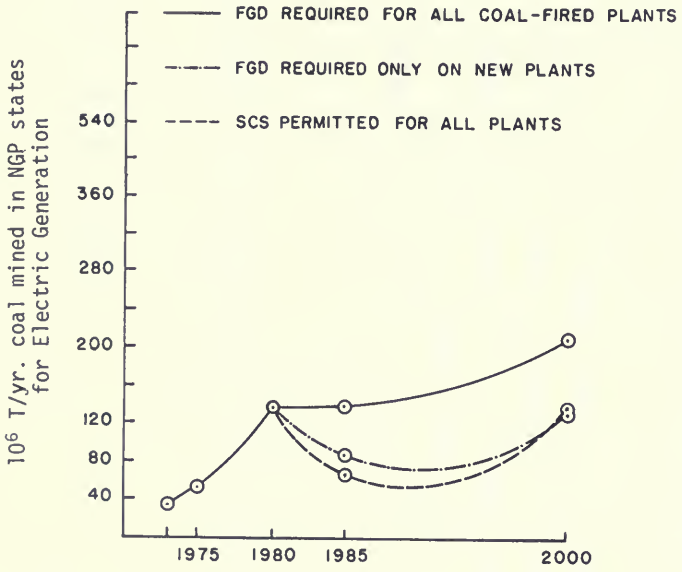
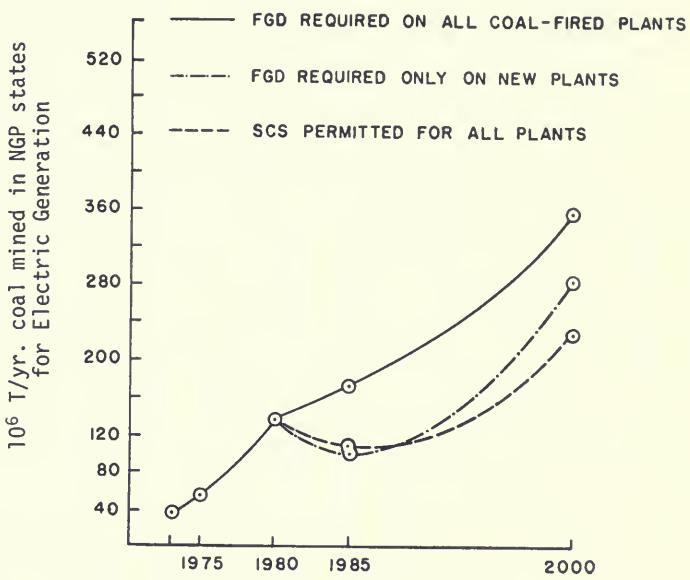


FIGURE 3B

THE EFFECT OF DIFFERENT POLLUTION CONTROL REQUIREMENTS ON DEMAND FOR NGP COAL FOR ELECTRIC GENERATION (5% annual growth in electric consumption)



SOURCE: "Projections of Northern Great Plains Coal Mining and Energy Conversion Development 1975 - 2000 A.D.", Montana University Coal Demand Study Final Report, March, 1976.

Until recently, projections of future consumption of electricity focused primarily on demographic variables and the rate and type of economic development taking place. These projections were remarkably stable and accurate, usually indicating an expected annual rate of growth in consumption of 7%-8%. This growth in consumption seemed to take place regardless of the price of the electricity, leading many to conclude that price was irrelevant. Individual private utilities, the Federal Power Commission (FPC), and various other government agencies (for instance, the Department of Interior's U.S. Energy Through the Year 2000, by DuPree and West)[5] have all produced projections of this sort.

Recently economists have noted that the apparent lack of influence of the price of electricity on the amount used is illusory. If electric prices are adjusted to take into account the impact of inflation, we find that the real average price of electricity in the U.S. declines from 6.08¢/KWH to 1.40¢/KWH between 1935 and 1969, an average annual decline of 4.3%.[6] Past trends show that a steady decline in price encourages a steady rise in consumption.

We are now entering a period of rising electric prices. The increased costs of environmental controls and fuel prices coupled with decreasing fuel supplies and the decrease in the rate of technological advance in electric generation have all contributed to reversing the long-term decline in real electric prices. In 1970, for the first time since 1946, the deflated average

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[5]Washington, D.C., December, 1972.

[6]Constant 1967 dollars, derived from Edison Electric Institute Year Book (1973), p. 53.

price of electricity rose slightly (1.8%). From February 1974 to February 1975, the deflated average price rose by 17.3%.[7] At the same time the rate of growth of electric consumption has slowed dramatically or even momentarily reversed. Although economists are careful to point out that other factors such as a depressed national economy and public conservation programs contributed to this overall result, it confirms their belief that the price of electricity remains one of the primary determinants of the quantity consumed and that rising real prices will have a significant retarding effect on future rates of growth of electric consumption.

Economists call this sensitivity of the amount of a good purchased to the price paid for that good the "price elasticity of demand." We measure it by dividing the percentage change in the quantity consumed by the percentage change in the price of the good. Many econometric estimates have been made of this sensitivity of electric consumption to real electric price changes.[8] Most estimates indicate that a 1% rise in real electric prices will lead, in the long run, to a 1%-2% decline in the predicted consumption level (a price elasticity of demand of -1.00 to -2.00).

If economists are correct, the typical electric utility and government projections of future levels of electric consumption--which ignore the long-term impacts of rising real electric rates--will seriously overestimate consumption levels. For instance, the Federal Power Commission (FPC) projects a 6.6%-7.2% annual rate of growth in electric consumption 1970-1990, while DuPree and West (Department of Interior) predict 6.9% annual growth 1970-1980.[9]

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[7]Derived from FPC News, Vol. VIII, No. 24 (June 20, 1975), p. 45, and Federal Reserve Bank of St. Louis Monetary Trends (August 20, 1975), p. 4.

[8]See Tables 9, 10 and 11 in MUCDS, Final Report for a summary of these studies.

[9]See Table 10, MUCDS, Final Report.

One economic study[10] found that in order to obtain the FPC growth rates, the real price of electricity would have to decline 24% from 1970-1980 and 12% each decade thereafter. Without such declines or with price rises, we can expect a much slower pattern of growth.

In addition to the impact of rising electric prices, increasing electric appliance saturation also suggests slower rates of growth of electric consumption in the future. If we assume that over the next 25 years no new electric energy intensive appliance is likely to come into mass use (such as an electric automobile), the rate of growth of electric consumption will slow as the percentage of households using all major electric appliances rises to complete saturation.

The Montana University Coal Demand Study reviewed all major projections of electric energy consumption[11] and chose two alternative methods to project electric energy consumption in the NGP coal market. The simplest approach was to assume that consumption will continue to grow at constant, but slower, annual rates. Future growth rates were estimated by using 1%, 3%, and 5% annual rates. These rates of growth were then applied to existing levels of consumption in the NGP coal market area.

In the other, more sophisticated, approach we used an econometric model which took into account the simultaneous influence of electric prices, natural gas prices, level of income, size of population, and the cost of electric appliances on the quantity of electricity purchased. This model was based

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[10] Chapman, Duane, Timothy Tyrrell, and Timothy Mount, "Electricity Demand Growth and the Energy Crisis." Science, Vol. 178, No. 4062 (November 12, 1972).

[11] See MUCDS, Final Report, pp. 25-32 and MUCDS Working Paper No. 1.

on the work of L.D. Chapman and his associates.[12] It is designed to estimate both the short and long run adjustments in the quantity of electricity consumed as a result of changes in causal variables such as electric prices.

Chapman et al. collected data on electric consumption, electric prices, natural gas prices, income, population, and electric appliance prices, from 47 states for 23 years (1947-1970). They used these data to statistically estimate the historical relationship between the variables. We adopted their estimates of these historical relationships for each of the states in the NGP coal market area.[13] After estimating what electric prices, natural gas prices, income and population levels would be for each state in the NGP coal market area in the future, we used these data and our already determined historical relationships to obtain a projection of the future level of electric consumption in each state.

The U.S. Water Resource Council's 1972 OBERS (Series E) projections of population and income were used in our projections. We had a more difficult time predicting the likely future levels of electric and gas prices--the key variables in our methodology. In order to reasonably bracket possibilities, we made projections of electric consumption using three alternative sets of future electric and gas prices. The lowest price growth assumptions were based on a region-specific study by the FPC[14] which estimated 0.42% to 1.08% annual increases in electric prices. The associated natural gas price increase was

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[12]Mount, T.D., L.D. Chapman, and T.J. Tyrrell. Electricity Demand in the U.S.: An Econometric Analysis, ORNL-NSF-EP-49, Oak Ridge, TN: Oak Ridge National Laboratory, June, 1973.

[13]Actually all of their results were not appropriate and/or available. As a result we had to do some statistical estimating ourselves. See MUCDS, Final Report, p. 33-37.

[14]FPC, 1970 National Power Survey.

set at 3% based on an estimate by the MIT Energy Laboratory of a "price control" situation.[15] An intermediate increase was set at 3% for electric and 5% for gas prices, and the "upper bracket" at 5% and 7% annual price increases for electricity and gas, respectively.

These future fuel price possibilities reflect the range used in several recent studies.[16] We also projected the effect of constant real prices (0% rate of growth).

In summary, our alternative "price-sensitive" approach to electric consumption projections focuses on the future cost of electricity and the cost of the closest substitute for electricity, natural gas. The prices of electricity and natural gas are assumed to be among the primary determinants of electric consumption. Therefore, we studied the impact of alternative levels of these prices.

The results of this price-sensitive model are presented in Table 1 and Figure 4. Note that rates of growth in consumption greater than 5% require fuel prices to decline. Even constant real electric and gas prices lead to rates of growth in electric consumption much lower than historic trends. Annual fuel price increases on the order of 3% for electricity and 5% for gas lead to an actual decline in electric consumption after 1985. This dramatizes the potential importance of fuel prices in controlling consumption.

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[15] Policy Study Group of MIT Energy Lab, "Energy Self-Sufficiency: An Economic Evaluation," Technology Review, LXXVI, No. 6 (May, 1974).

[16] Chapman, Duane, et al., "Electric Demand and Utility Capacity Planning," Cornell Agricultural Economics Staff Paper No. 73-23 (November, 1973), and Chapman, Duane, and Timothy Mount," Electric Demand and the Financial Problems of Electric Utilities," Cornell Agricultural Economics Staff Paper No. 74-25 (September, 1974).

TABLE 1

ANNUAL GROWTH RATES IN ELECTRIC CONSUMPTION

USING THE PRICE-SENSITIVE MODEL

Annual Percent Price Change (Electric, Gas)	(% Per Year) 1974-1980	1980-1985	1985-2000
A. All FGD Market			
0%, 0%	5.86	4.20	2.98
FPC, 3%	5.45	3.53	2.14
3%, 5%	4.00	1.14	-0.84
5%, 7%	2.79	-0.83	-3.26
B. Partial FGD Market			
0%, 0%	6.31	4.42	3.08
FPC, 3%	5.88	3.72	2.20
3%, 5%	4.45	1.36	-0.75
5%, 7%	3.23	-0.61	-3.18

SOURCE: MUCDS, Table 18

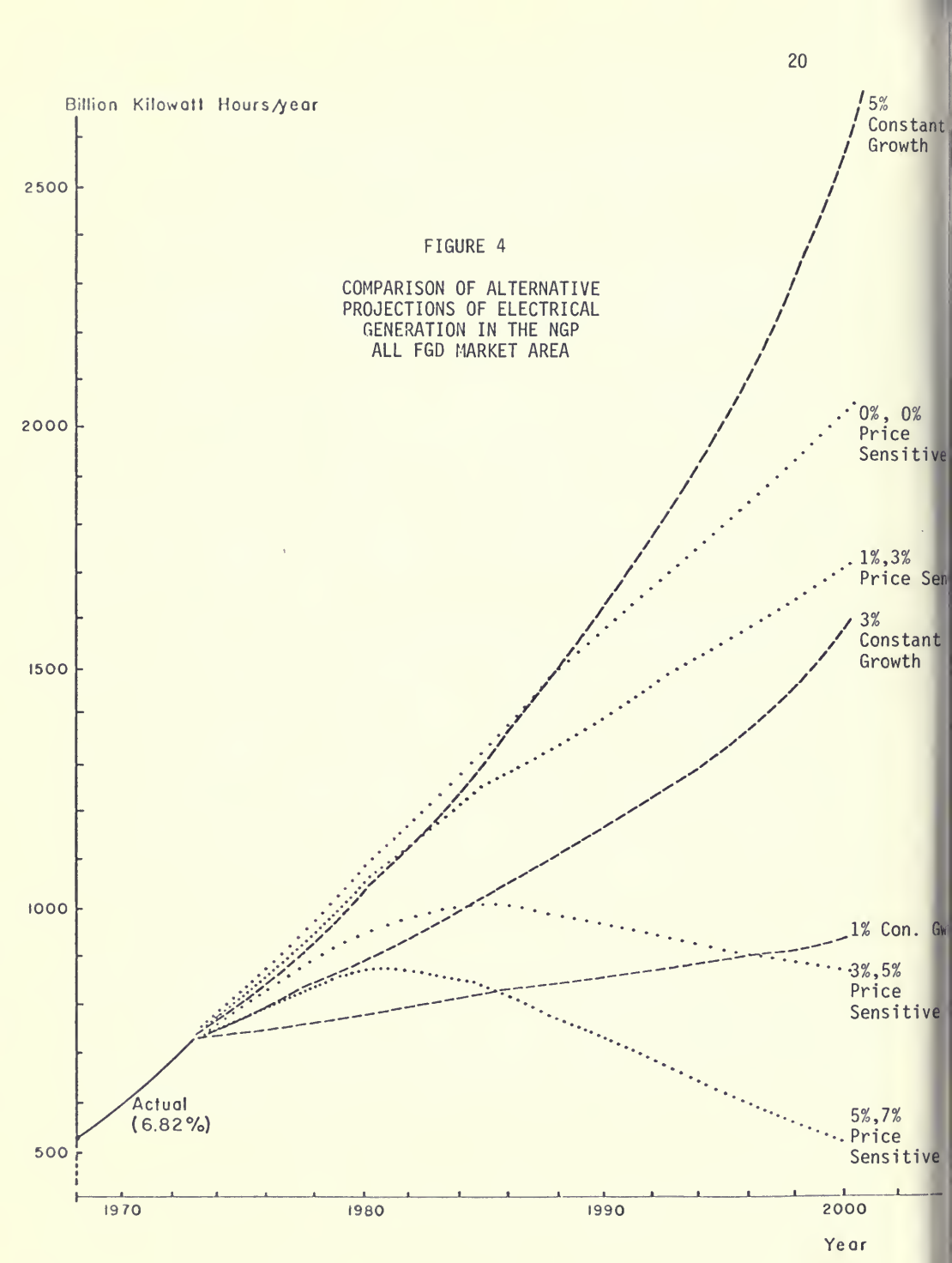


FIGURE 4

COMPARISON OF ALTERNATIVE PROJECTIONS OF ELECTRICAL GENERATION IN THE NGP ALL FGD MARKET AREA

Figures 5 and 6 indicate the impact of these assumptions about the rate of growth of electric consumption on the demand for NGP coal given "reasonable" assumptions about the other determinants of NGP coal demand. Figure 5A shows that the current rate of (planned) expansion in mining in the NGP will not continue unless the consumption of electricity grows at near its historic rate (greater than 5% per year). Figure 5B shows that this will happen only if the real price of electric energy falls. Thus, any rise in energy prices will severely restrict the growth in the demand for NGP coal. Moderate rates of growth in electric consumption (3%) will lead to a leveling off of demand for NGP coal near the existing 1980 contract levels.

Figures 6A and 6B compare our two approaches to determining what effects the consumption of electricity have on the demand for NGP coal. Constant consumption growth rates are compared to the growth rates produced by rising electric and natural gas prices with "similar" results grouped together. It is obvious that rising energy prices have an important long-run dampening effect on the demand for NGP coal. Although our 5% constant growth projection is similar to the constant prices projection, and 1% constant growth is similar to the 5% and 7% annual increase in electric and NG price projection for 1985, they diverge significantly by the year 2000, with the price-sensitive projections yielding much lower results. The message again is that energy prices may have a significant impact on energy consumption and, therefore, the demand for NGP coal.

4.3 The Role of Coal in Satisfying this Demand for Electricity in the NGP Coal Market Area.

After estimating the future level of electric consumption in the Northern Great Plains market area, we projected what fraction of that electricity would be generated by burning coal. This was the most uncertain step in the Montana

FIGURE 5A

EFFECTS OF DIFFERENT RATES OF GROWTH IN ELECTRIC CONSUMPTION ON DEMAND FOR NGP COAL

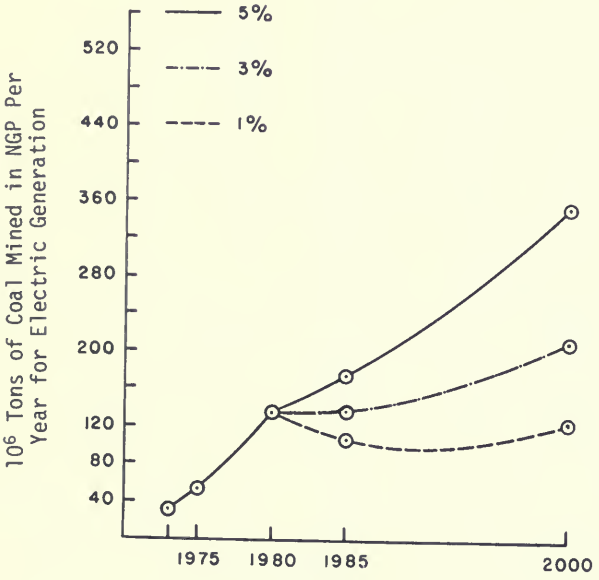
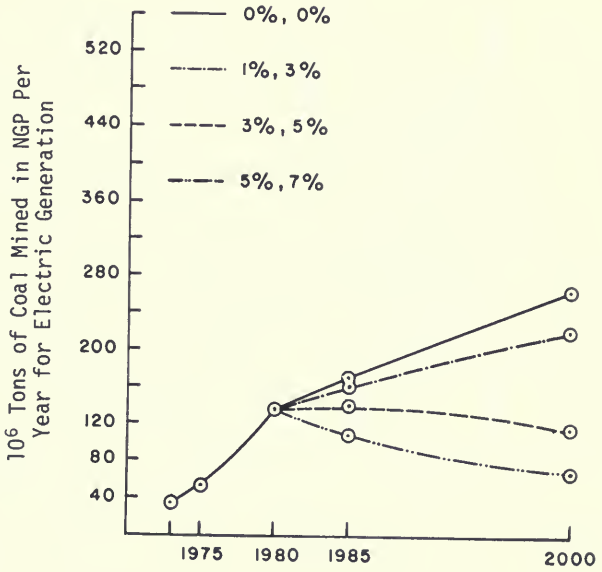


FIGURE 5B

EFFECTS OF DIFFERENT RATES OF INCREASE IN ELECTRICITY AND NATURAL GAS PRICES ON DEMAND FOR NGP COAL

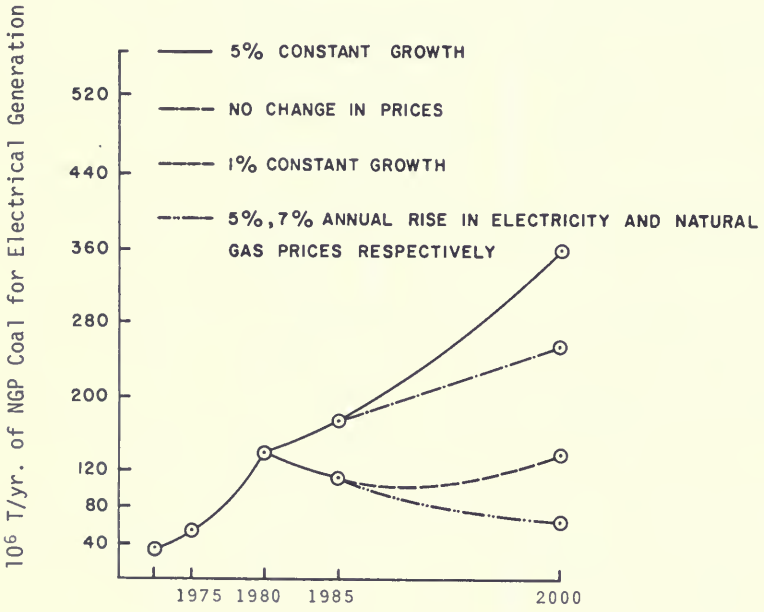


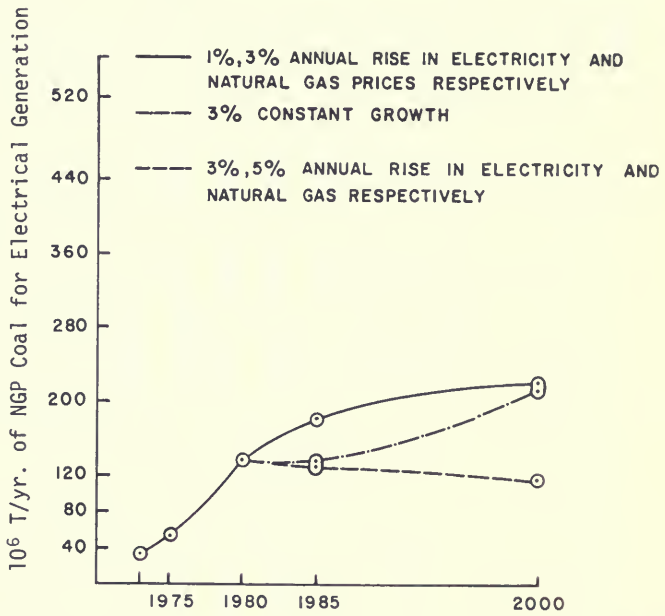
SOURCE: "Projections of Northern Great Plains Coal Mining and Energy Conversion Development 1975-2000 A.D.", Montana University Coal Demand Study Final Report, March, 1976.

FIGURE 6A

FIGURE 6B

COMPARISON OF IMPACT OF CONSTANT GROWTH IN CONSUMPTION AND CONSTANTLY RISING ENERGY PRICES ON THE DEMAND FOR NGP COAL FOR ELECTRICAL GENERATION





SOURCE: "Projections of Northern Great Plains Coal Mining and Energy Conversion Development 1975 - 2000 A.D.," Montana University Coal Demand Study Final Report, March, 1976.

University Coal Demand Study. The mix of fuels used in the future to generate electricity will not be determined solely by electric utilities making cost minimizing choices.

That mix of fuels is also the target of state, federal, and foreign government policies. We cannot easily predict the rate of development (and cost, reliability, safety, and public acceptability) of nuclear power, the availability of oil and natural gas for boiler fuels, the relative cost of residual oil, the enforcement of emission and ambient air pollution standards.

Again, we used two approaches in determining "fuel mix." First we surveyed the current status of problems associated with the expansion of hydroelectric and nuclear generating capacity.[17] On the basis of this survey, we projected future hydroelectric and nuclear generating capacity for 1980, 1985, and 2000. For the future, gas-fired generation was assumed to remain constant at 1973 levels and oil-fired generation was assumed to be zero. Given our projections of total electric generation from the previous step, we then subtracted this non-coal generation from the total to obtain the amount of coal-fired electric generation. This was called the "residual" approach. The key "swing" variable in this approach was the projected amount of nuclear generating capacity. Our nuclear projections are generally lower than those from previously published reports. We based them for the years 1980 and 2000 both on published construction schedules for announced plants and a review of the current status of the nuclear power industry in general. This means that the nuclear projections for these years reflect the electric utility industry's high growth expectations. The projection for the year 2000 was

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[17] See MUCDS Working Papers #5, #6 and #7.

based on the alternative assumptions about the growth in electric consumption discussed previously. In addition, it was assumed that beyond 1985 50% of all new generation would be nuclear fueled in our All FGD market, and 40% would be nuclear fueled in our Partial FGD market.

Our nuclear projections are lower than previous studies essentially because we assume that electric energy consumption will be lower than the recent historical trend. This means that electric utilities' current expectations will not be fulfilled. We made other important assumptions in our nuclear projections: That the current slippage in nuclear power plant construction from planned schedules will continue and that there will be no dramatic improvement in the average nuclear power plant capacity factor.

The other approach used to estimate the fraction of coal-fired electric generation in the NGP coal market area was to assume that the share of total coal-fired electric generation would remain constant in the future. The current coal-fired share of electric generation is 39.0% in the All FGD market and 13.8% in the Partial FGD market. This assumption contains an indirect nuclear projection: If coal holds its 1973 share, NG does not increase as a fuel for electric generation, oil-fired electric generation remains at near zero levels, and hydroelectric generation increases as we have estimated for our market areas, a residual amount of electric generation will have to be provided by nuclear generation.

Figures 7A and 7B indicate the effect of these alternative assumptions about fuel mix on the projected demand for NGP coal. The assumption that coal will fill a residual demand after reasonable levels of nuclear and hydroelectric development have taken place leads to a projection of <u>decline</u> in the demand for NGP coal between 1980 and 1985 even at moderate (3%) rates of growth in consumption (or, similarly, at moderate rates of rise in electric

FIGURE 7A

EFFECTS OF FUAL-MIX ASSUMPTION ON DEMAND FOR NGP COAL FOR ELECTRIC GENERATION
(3% annual growth in Electric Consumption)

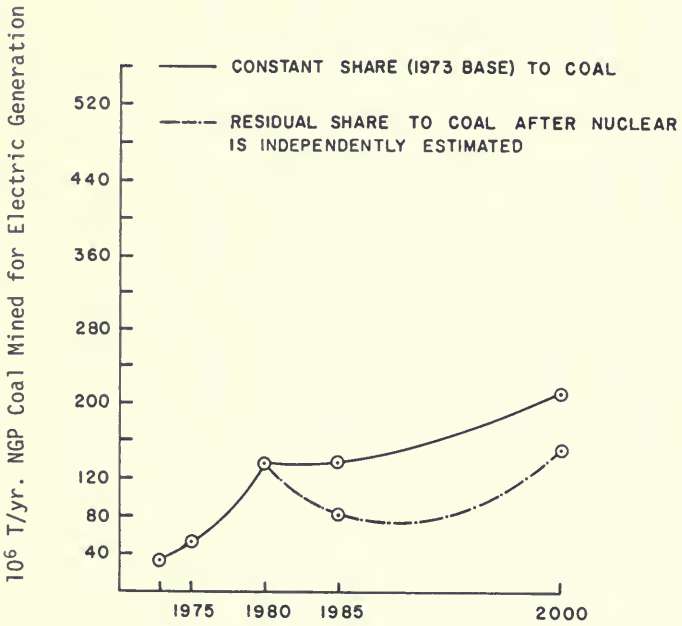
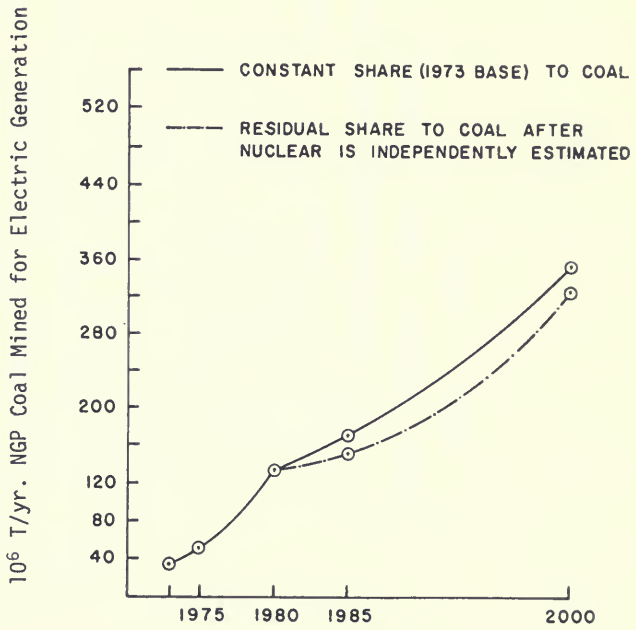


FIGURE 7B

EFFECTS OF FUEL-MIX ASSUMPTION ON DEMAND FOR NGP COAL FOR ELECTRIC GENERATION
(5% annual growth in Electric Consumption)



SOURCE: "Projections of Northern Great Plains Coal Mining and Energy Conversion Development 1975 - 2000 A.D.," Montana University Coal Demand Study Final Report, March, 1976.

and NG prices, e.g., 1%, 3%). The growth in coal consumption for electric generation between 1985 and 2000 is also dramatically reduced. This may seem unreasonable to some, particularly utilities, but this result is brought about by the nuclear construction programs planned between 1973 and 1980. These construction schedules assume continued high growth rates in electric energy consumption, creating a generating base in 1980 that may be too large for the demand that actually develops. Given that this nuclear capacity will already exist (or will be under construction), utilities may adjust by reducing their demand for coal below the existing contract levels.

Although this result is not "unreasonable," it obscures the actual mix of nuclear, hydroelectric, and coal-fired generation that utilities are trying to establish. We assume, given no knowledge to the contrary, that without "supply" constraints, the mix of fuels chosen by utilities will not vary with the level of demand for electricity. To estimate this intended fuel mix, the assumption of a constant share to coal vis-a-vis other fuels may be more reasonable as indicated by the 1973 mix of coal, nuclear, hydroelectric, etc. Figure 7B indicates that at higher rates of growth in electric consumption (ones closer to utilities' expectations) both assumptions generate similar demand for NGP coal.

4.4 The Role of the NGP in Supplying this Coal for Electric Generation

To finally estimate the demand for NGP coal, we must determine what fraction of the coal needed for coal-fired generation in the NGP coal market area will come from that area. This will give us the quantity of NGP coal needed for electrical generation in the future.

The simplest approach is to assume that since the market for NGP coal is defined in terms of where NGP coal has a cost advantage, all new coal-fired

electric generation will be supplied by NGP coal. Existing plants in the NGP market area which did not have contracts for NGP coal in 1973 would be excluded because it was assumed that their long-term existing coal contracts would have to be honored.

However, our market boundaries only establish a line at which NGP coal is as cheap as midwestern coal. Given the uncertainties involved, it would be more accurate to picture a broad area where the two coals are equally costly to use. This area includes the populous and industrial states of Michigan, Indiana, Illinois, Wisconsin, and Texas. Using this broad area, we can see that there is significant room for alternative cost-minimizing calculations by the utilities or room for real discretion in choosing between coal sources. To reflect this possibility, we assumed that only a certain share of the coal demand in the NGP coal market area would go to the NGP states. This share was calculated by looking at the existing contracts for delivery of NGP coal to utilities in the NGP coal market area in 1980. This amount of coal was then compared to the total amount of coal needed to generate electricity in the market area as calculated previously.[18] Thus, the 1980 contract-based share of the market that would go to NGP was determined. We assumed this share would remain constant beyond 1980.

Figures 8A and 8B indicate the impact of these alternative assumptions about coal source on the demand for NGP coal. Note that the assumption that

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[18]The total amount of coal needed for electrical generation will obviously depend upon the rate of growth of consumption in electric energy. In an earlier section, we indicated that we experimented with seven different such consumption projections. Here we are trying to estimate how the electric utility industry will divide its purchases between NGP coal and other coal sources. We therefore use the highest rate of growth in electric consumption 1974-1980, one that approximates the utilities' current expectations, to calculate the 1980 contract-based share NGP coal will have of the market.

FIGURE 8A

EFFECT OF COAL SOURCE ASSUMPTION ON DEMAND
FOR NGP COAL FOR ELECTRIC GENERATION
(3%/Yr. growth in Electric Consumption)

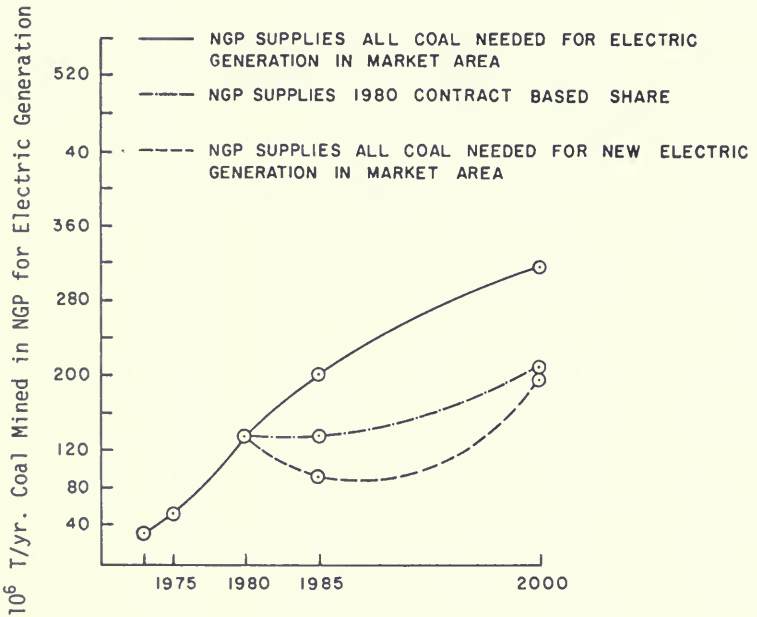
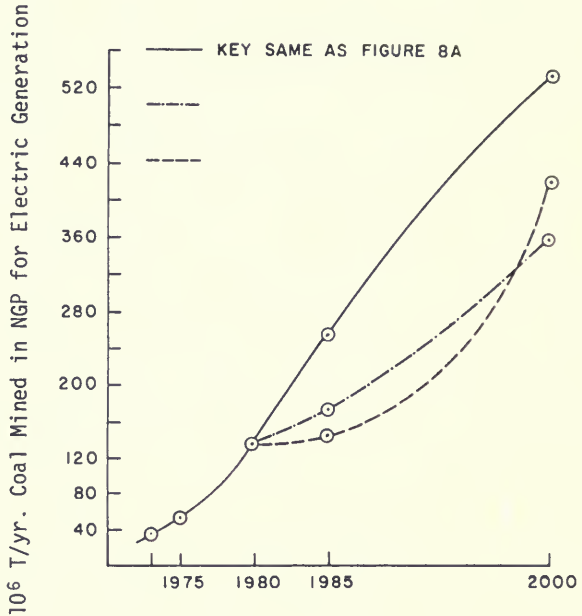


FIGURE 8B

EFFECT OF COAL SOURCE ASSUMPTION ON DEMAND
FOR NGP COAL FOR ELECTRIC GENERATION
(5%/Yr. growth in Electric Consumption)



SOURCE: "Projections of Northern Great Plains Coal Mining and Energy Conversion Development 1975-2000 A.D.," Montana University Coal Demand Study Final Report, March, 1976.

the NGP supplies all coal needed by new electric generation in the NGP market area leads to a dramatic decline in the demand for NGP coal past 1980 despite moderate rates of growth in electric consumption. This is because the assumption does not allow any existing plants to switch over to NGP coal, even over a 12-year period. This result (and, therefore, this assumption) seems unreasonable, suggesting that an assumption that the NGP will supply all coal consumed in the market area might be a better estimate of electric utility expectations. However, it is also possible that electric utilities are overestimating the future demand for electricity and therefore the 1980 result based on current contracts will be too high if growth in consumption moderates. However, at the moment the assumption that the NGP will fill the 1980 contract-based share seems most reasonable.

Note that while the assumption that the NGP supplies all new coal-fired electric generating plants reduces or limits demand for NGP coal 1980-85, in the long run (1985-2000) it leads to rapid expansion in NGP coal demand.

Our estimates of coal sources for utilities and our specific projection of the demand for NGP coal for 1980 were based on an index of coal contracts for the Northern Great Plains which is part of the Montana University Coal Demand Study.[19] Since neither utilities nor coal companies are required to report these contract data, this information had to be pieced together from a variety of sources. It is, however, the best information publicly available regarding contracts for NGP coal. The totals are, as a rule, underestimates of the coal actually under contract. Since the lead time necessary to expand an existing mine or open a new one is long, and since utilities usually will

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[19] William Tomlinson, MUCDS Working Paper No. 4.

not build a generating facility until they have a long-term contract in hand, we can consider these 1980 contract data a firm minimum estimate of the coal that will be mined in the NGP states in 1980. The contract total for 1980 is 135.7 million tons of NGP coal. Table 2 summarizes these data.

4.5 Alternative Projections for NGP Coal Production for Electric Generation

Thus far, we have outlined the alternative sets of assumptions made to generate various projections of the demand by electric utilities for NGP coal. These sets of alternative assumptions are summarized in Table 3. Altogether they could generate 56 different projections.[20] This may seem to be an unreasonably and unworkably large number of alternative scenarios. However, it should be understood that the intent of the Montana University Coal Demand Study is not to produce one "best" projection, but to generate a set of projections each appropriate under a different set of future conditions. We attempted to demonstrate the sensitivity of the projections to various future decisions and events, thus increasing their useful "life expectancy" in a very uncertain world.

In the preceding pages we have also indicated the impact each assumption has on the projected level of demand for NGP coal. Tables 4 and 5 present this same information for the 1980 contract-bases share coal source assumption. The "most likely" levels of development (enclosed by a dashed line) assume that:

1. flue gas desulfurization or the combustion of low-sulfur coal will be required for all coal-fired plants;

2. electric consumption will grow at a rate much slower than in previous years (3%-5% per year) brought about by modest annual rises in real electric

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[20] All the projections are found in the MUCDS, Final Report. Actually, many more projections were made. For instance, a smaller market created by allowing supplementary pollution controls on both existing and new plants was considered, as well as the possibility that NGP coal would fill all coal needs in the market area.

TABLE 2

NORTHERN GREAT PLAINS COAL CONTRACT DATA SUMMARY

Production Estimate 1980 by State of Origin

State of Origin	Mine Production Estimate	Contract Estimate
Montana	56.92 million tons	37.52 million tons
Wyoming	101.30 million tons (min.)	84.26 million tons (min.)
	143.50 million tons (max.)	94.21 million tons (max.)
North Dakota	24.67 million tons (min.)	13.92 million tons
	27.47 million tons (max.)	
Total	182.89 million tons (min.)	135.70 million tons (min.)
	227.89 million tons (max.)	145.65 million tons (max.)

SOURCE: MUCDS, Working Paper No. 4

TABLE 3

ALTERNATIVE ASSUMPTIONS USED IN MAKING PROJECTIONS

Market	Growth	Rate of Increase in Electric Consumption (% per year)	Fuel Mix	Coal Source
All FGD	Constant	1% 3% 5%	Constant Coal Share) Coal Share Residual)	NGP supplies 1980 share
Partial FGD	Constant	1% 3% 5%	Constant Coal Share) Coal Share Residual)	NGP supplies all new
		Rate of Electric Price, Gas Price Rise (% per year)		
All FGD	Price Sensitive	0%, 0% FPC, 3% 3%, 5% 5%, 7%	Constant Coal Share) Coal Share Residual)	NGP supplies 1980 share
Partial FGD	Price Sensitive	0%, 0% FPC, 3% 3%, 5% 5%, 7%	Constant Coal Share) Coal Share Residual)	NGP supplies all new

TABLE 4

COAL PRODUCTION IN THE NORTHERN GREAT PLAINS FOR ELECTRIC GENERATION BASED ON CONSTANT GROWTH IN ELECTRIC CONSUMPTION AND THE 1980-BASED CONTRACT SHARE OF ALL COAL DEMAND

Part A: Coal Production assuming that Coal-Fired Generation Maintains its Current Share of Electric Energy Production

Growth in Electrical Production	(Millions of Tons) 1980	1985	2000
All FGD Market Estimate			
1%	136	108	126
3%	136	137	214
5%	136	173	360
Partial FGD Market Estimate			
1%	136	34	52
3%	136	63	140
5%	136	99	285

Part B: Coal Production based on the Assumption that the Residual Share of the Fuel Mix within the NGP Market Area will be filled by Coal-Fired Generation

Growth in Electrical Production	(Millions of Tons) 1980	1985	2000
All FGD Market Estimate			
1%	136	25	37
3%	136	83	154
5%	136	154	335
Partial FGD Market Estimate			
1%	136	0	0
3%	136	20	91
5%	136	91	272

SOURCE: MUCDS, Final Report, Table 22.

TABLE 5

COAL PRODUCTION IN THE NORTHERN GREAT PLAINS FOR ELECTRIC GENERATION BASED ON PRICE-SENSITIVE ESTIMATES OF GROWTH IN ELECTRICAL CONSUMPTION AND THE 1980-BASED CONTRACT SHARE OF COAL DEMAND

Price-Sensitive Coal Production Assuming that Coal-Fired Generation Maintains its Current Share of Electric Energy Production

Annual Rate of Price Increase (Electric, Gas)	(Millions of Tons) 1980	1985	2000
All FGD Market Estimate			
0%, 0%	136	171	266
FPC, 3%	136	161	221
3%, 5%	136	130	115
5%, 7%	136	109	66
Partial FGD Market Estimate			
0%, 0%	136	99	194
FPC, 3%	136	89	149
3%, 5%	136	58	43
5%, 7%	136	37	0

Price-Sensitive Coal Production Based on the Assumption that the Residual Share of the Fuel Mix within the NGP Market Area will be filled by Coal-Fired Generation

Annual Rate of Price Increase (Electric, Gas)	(Millions of Tons) 1980	1985	2000
All FGD Market Estimate			
0%, 0%	136	151	238
FPC, 3%	136	132	186
3%, 5%	136	72	38
5%, 7%	136	30	0
Partial FGD Market Estimate			
0%, 0%	136	92	178
FPC, 3%	136	73	126
3%, 5%	136	13	0
5%, 7%	136	0	0

SOURCE: MUCDS, Final Report, Table 23

prices (1%-3% per year);

3. coal will retain its 1973 share of electric generation rather than being significantly displaced by nuclear generation; and

4. the NGP will supply that share of the market indicated by the established 1980 contracts and the projected level of coal-fired generation needed at that time. The "reasonableness" of each of these assumptions has been discussed.

Our projections suggest it is quite possible that coal development in the Northern Great Plains for electrical generation will not increase much beyond the level indicated by current 1980 contracts (136 million tons). Real electric prices would have to rise very little (1% per year or less) or decrease for substantial further demand for NGP coal electrical generation to develop. Our model indicates this situation would allow a 3%-5% per year increase in electric consumption and a concomitant rise in the demand for NGP coal by the year 2000 of 60% to 160% above the 1980 contract levels. Even this growth represents a substantial decelleration in the current rate of development of NGP coal. If state and federal pollution regulations do not require flue gas desulfurization or the combustion of low-sulfur coal for all coal-fired plants, the demand for NGP coal in 1980 and 1985 will be substantially below the current 1980 contract levels, and with moderate rates of growth in electric consumption may not reach those 1980 contract levels by the year 2000.

5. THE DEMAND FOR NGP COAL FOR GASIFICATION

Another primary source of (potential) demand for NGP coal is feedstock to produce substitute (synthetic) natural gas (SNG). The likelihood and extent of such development depends on the value of such a gaseous fuel, the cost of producing it, and the political action taken by governments at various levels which influence both of these.

5.1 The Cost of Producing SNG from Coal

Since no one has attempted the large scale production of pipeline quality SNG, costs are somewhat speculative. The MUCDS[21] surveyed the various estimates available, adjusted them to take into account inflation and differing discount rates, and concluded that the cost of a synthetic natural gas from a commercial size plant (250 million cubic feet/day) would range from $2.50-$3.50 per million BTUs of gaseous fuel (late 1974 dollars). Most estimates by industry and government are at the lower end of this range.

5.2 The Value of SNG

The value of SNG depends upon the demand for energy and the price, availability and suitability of other alternative energy sources. As the rate of consumption of energy increases, the value of SNG as well as other types of energy also increases. On the other hand, the cheaper, more available, and more suitable other energy sources are compared to SNG, the lower the value. For this reason, we focus on the cost of close substitutes for SNG in analyzing its value.

5.2.1 Substitutes for SNG

The closest competitor to SNG is natural gas (NG). Both the price of natural gas and its availability (supply) crucially determine the feasibility of coal gasification. The critical question is whether natural gas could be made available at prices lower than SNG, in quantities great enough to eliminate SNG demands. Current production of NG is limited by both low regulated prices and industry uncertainty about future price regulation. The MIT Energy

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[21] Final Report, p. 79-91.

Laboratory (MacAvoy and Pindyck)[22] has estimated how the quantity of NG made available would respond to higher prices. Using a complex econometric model, they estimated than an average wholesale price of $0.61 MMBTU (in 1974 dollars) would lead to the production and sale of all the NG necessary to satisfy demand by 1980. This would leave no market for SNG. Some experts have questioned their estimates of physical NG reserves, but even if the price of NG had to rise to four times the level they suggest to bring supply in line with demand, natural gas still would be available at prices below the cost of SNG and no market would exist in the U.S. for SNG.

Coal itself also competes, at least for industrial sales of SNG. At a price of $4.50 per ton, coal costs about $0.265 per million BTUs, or the energy equivalent of $0.265 per Mscf of SNG. This is one tenth the cost of an equivalent amount of SNG. Whether coal will substitute for NG (and SNG) depends upon the development of appropriate air pollution control technology that would allow industrial users to satisfy state and federal regulations.

Coal can also be burned to produce electricity which can substitute for NG (and SNG) in residential and commercial space heating and cooling. Hammond and Zimmerman[23] of the MIT Energy Laboratory project heating costs significantly lower from electricity-powered heat pumps than from SNG using assumptions biased in favor of SNG technology and gas burning efficiency. This again eliminates the market for SNG.

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[22]MacAvoy, Paul, and R. Pindyck. Price Controls and the Natural Gas Shortage (Washington, D.C.: American Enterprise Institute for Public Policy Research, May, 1975).

[23]Hammond, Ogden, and Martin B. Zimmerman. "The Economics of Coal-Based Synthetic Gas," Technology Review, Vol. 77, No. 8 (July/August, 1975) pp. 15-22.

If either coal or coal-fired electricity is substituted for NG, the demand for NGP coal will rise even though coal gasification does not take place. As mentioned before, this inter-fuel substitution is the weakest part of our analysis. We have estimated an upper limit to what the demand for NGP coal would be if such substitution for NG takes place. Our "most likely" projection does not include an increase in NGP coal demand because of this sort of substitution. Our "high projection" adds 33-63 million tons per year of NGP coal by the year 2000 to reflect this possibility.

5.3 The Role of Government

All of the above discussion is based on the assumption of private cost-minimizing by energy producers and consumers. However, predicting the time path of coal gasification is a problem in political economy, and we must make some assumptions about the way government decisions may influence coal gasification. Government restrictions of NG production, import, and price may create a market for SNG. Similarly, government subsidies for SNG may lower the cost of SNG production from coal and make it viable. We assume that public decisionmakers will "most likely" encourage cost minimization in energy supply and, therefore, not overrule the cost considerations mentioned above.

5.4 Conclusion and Projections

All factors considered, we forecast that no commercial production of SNG will occur in the NGP in 1980 or 1985. Since commitments must be made in the next two to four years for production by 1985, we stand confident of this forecast. To forecast the production of SNG (or any other commodity) in the year 2000 is exceedingly difficult. Society's ignorance of fossil fuel reserves, together with the uncertainty of foreign fuel-source prices and

availability, make forecasting NG production for the year 2000 almost a guessing game. We assume (almost arbitrarily) that cost relationships, technology, and regulatory factors will remain close enough to the currently foreseeable situation that SNG production also will remain economically unfeasible in the year 2000.

Thus, our "low" and "most likely" projections are for no gasification of coal in the NGP in this century. One can easily devise a set of assumptions which would change this judgment for the period after 1985--technological advance could lower SNG costs; engineers may be unable to design environmentally acceptable ways to use coal in place of gas; government control of NG prices may retard NG production; NG reserves may turn out to be much lower than expected; the Canadian government may cut off the NGP region from Canadian natural gas and oil supplies in such a way that replacement by Alaskan and NGP production would be impossible; enormous subsidies might be offered to get SNG production under way; etc. Given that any combination of these events is possible, our "high" projection is that while no SNG plants will be built in the Northern Great Plains by 1980, three such plants will operate in 1985 (one in each state). We project no increase from 1985-2000. Table 6 presents these projections.

6. A COMPARISON OF THE MUCDS PROJECTIONS WITH OTHER PROJECTIONS

Below we compare the MUCDS projections with other national projections. We intend to demonstrate what we feel is the superior logic of our projections and the importance of the assumptions made in generating such projections. If these assumptions are not explicit and combined in a systematic way, the results will be confusing and inaccurate.

6.1 The Northern Great Plains Resource Program

The only other detailed analysis of projected levels of coal development

TABLE 6

NGP COAL DEMAND FOR REPLACEMENT OF NATURAL GAS
BY COAL GASIFICATION AND DIRECT COMBUSTION OF COAL AS A BOILER FUEL

Coal Gasification Plants in the Northern Great Plains

	1980	1985	2000
"Most likely"	0	0	0
Low	0	0	0
High	0	3	3

Note: All plants rated at 250 MM Scf/day. One plant each will be located in Montana, Wyoming, and North Dakota in the high estimates.

Coal Requirements for Gasification Plants in the Northern Great Plains

	(Million Tons per Year)		
	1980	1985	2000
"Most likely"	0	0	0
Low	0	0	0
High	0	22.5	22.5

Note: Each plant requires 7.5×10^6 tons per plant-year of operation.

Consumption of NGP Coal as a Boiler Fuel to Replace Natural Gas

	(Million Tons per Year)		
	1980	1985	2000
"Most likely"	0	0	0
Low	0	0	0
High	0	16-31	33-63

in the NGP appears in the Northern Great Plains Resource Program (NGPRP) publication National and Regional Energy Considerations Work Group Report (February, 1974).[24] Since the Montana University Coal Demand Study and the NGPRP reached quite different conclusions about coal development for gasification and electric generation, we analyzed in some detail the source of these differences. Here we summarize the results of that analysis.

6.1.1 NGPRP Projections of NGP Coal Development for Electric Generation

The NGPRP makes different (and in our view inappropriate) assumptions about the market area open to NGP coal, the size of existing contracts for NGP coal, the rate at which electric consumption (and thus the demand for coal) will grow, the percentage of electric generation that will be coal-fired, and the proportion of the national demand for coal that will be filled by the NGP. Some of these differences lead them to overestimate the demand for NGP coal, some lead them to underestimate the demand. The net effect is projections in the same range as our projections. This we feel is a coincidence. Table 7 compares the two projections. The most important divergence is in the "high" estimate for the year 2000 where the cumulative impact of the NGPRP's high growth rates in electric consumption leads to a projected demand for NGP coal much higher than ours.

The NGPRP defines a market area for NGP coal that is similar to our All FGD market, although somewhat (30%) smaller. Their contract data suggest existing commitments in 1980 that are only 62% of our own estimates (84.11 vs. 135.7 million tons per year). The NGPRP uses Federal Power Commission and utility projections of electric consumption growth that are not price-sensitive.

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[24]Hereinafter cited as NGPRP (1974). A summary document which contains no changes in the coal projection was completed in April, 1975, entitled Effects of Coal Development in the Northern Great Plains--hereinafter cited as NGPRP (1975).

TABLE 7

NGPRP AND MUCDS PROJECTIONS OF NGP COAL NEEDED FOR ELECTRIC GENERATION

	1980	1985	2000
	(Millions of Short Tons)		
NGPRP			
Low	91	108	144
Intermediate	107	139	241
High	107	229	666
MUCDS			
1%	136	108	126
3%	136	137	214
5%	136	173	360

SOURCE: Table 28, MUCDS, Final Report, p. 85.

This leads them to project growth rates much higher than our own (5.5%-7.5% per year vs. our 1%-5% per year). In addition, they assume that NGP fills a much greater proportion of midwestern coal consumption. The NGPRP market definition assumes that all increases in coal-fired generation within the market area are supplied by NGP coal. We assume, from 1980 contract data, that NGP coal supplies 77% of the 1980 coal consumption within the NGP coal market area (in our "most likely" projection). On the other hand, NGPRP assumes that nuclear generation will fill a much larger share of the demand for electricity. They project that coal's share of electric generation in the market area will decline to 15.6%-28.4% in 2000, while we assume the share will be 39%-50%. The validity of each of these NGPRP assumption is discussed in MUCDS, Final Report, pages 98-114.

6.1.2 NGPRP Projections of NGP Coal Development for Gasification

The MUCDS forecasts of gasification activity are lower than most other contemporary forecasts, including those of the NGPRP. Table 8 compares the two.

NGPRP gives little information about the methodology which led to the specific numbers used in the gasification forecasts, making comparison difficult.

The NGPRP is far more certain that gasification[25] will proceed immediately. They list over a half dozen "announced" plants to be built in the area. In June 1974, they wrote that "a number of energy companies" had shown "substantial interest" in NGP gasification and had "invested in research programs and plant development planning." At this time (January, 1976) no plants have gone beyond

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[25] NGPRP, following the U.S. Bureau of Mines, assumes SNG will cost $0.91-$1.27/Mscf (1972 prices). This makes SNG appear competitive with natural gas. We used a $3.00/Mscf (1974 prices) figure drawn from Project Independence Report and recent statements by utilities.

TABLE 8

COMPARISON OF NGPRP AND MUCDS GASIFICATION PROJECTIONS

	1980	1985	2000
NGPRP	(Number of Plants)		
Low	0	0	0
Most likely	0	7	16
High	7	13	41
	(Millions of Short Tons of NGP Coal)		
Low	0	0	0
Most likely	0	53	121
High	53	153	311
MUCDS	(Number of Plants)		
Low	0	0	0
Most likely	0	0	0
High	0	3	3
	(Millions of Short Tons of NGP Coal)		
Low	0	0	0
Most likely	0	0	0
High	0	22.5	22.5

SOURCE: Table 28, MUCDS, Final Report, p. 85, and p. 86.

the planning stage. Most projects seem to have been indefinitely postponed pending technological breakthroughs, governmental subsidies, or more certain market indicators.

In addition, the NGPRP draws its energy demand forecasts from the Department of Interior publication United States Energy Through the Year 2000 (1972), which projects future consumption on the basis of past trends. Rises in energy prices can neither reduce demand nor increase supply. Our approach was to consider both economic responses. More elaborate econometric models (e.g., MIT Energy Lab) have shown the significant impact such adjustments can have on both natural gas demand and availability.

Finally, NGPRP does not consider the possibility of a switch away from gaseous fuels to other fuel sources. We specifically consider "switch-overs" such as to electricity (in home use) and to direct coal burning (in industrial use) that would occur at higher gas prices and concluded that synthetic natural gas would not compete in any market except, perhaps, at heavily subsidized prices. If, however, such "switch-overs" take place, the demand for NGP coal for export could increase as we have previously shown.

6.2 Project Independence Report

The Federal Energy Administration, as part of its Project Independence Report (1974) (PIR) has projected both the coal exports out of the NGP and the coal "production potential" of the NGP. These projections are based on an elaborate and complex model of both supply and demand and how the two interact as energy prices change. This model has not been released as of November 1975. As a result, no detailed explanation of the basis of FEA's results are possible.

PIR projects coal flows out of the NGP in 1985 which are only 25% of our estimate of firm 1980 contracts. Our contract information includes coal

mined to generate electricity for export; thus, it should be somewhat larger (as much as 50% larger), but not four times as large. Either the PIR model assumed that pollution control costs associated with midwestern coal would be minimal and thus generated a very small market for NGP coal (only as far east as Minnesota and western Wisconsin) or made some other assumption that we cannot determine.

The PIR also published "coal production potential" estimates. These appear to be estimates of what could be produced, not what will be produced. These estimates for the NGP fall within our All FGD market projections.

The PIR does not seem to provide reliable regional projections of coal development. Their estimates of what the flows of coal will be between regions are not consistent with their estimates of what the "coal production potentials" of regions are and some of those "flows" are clearly suspect.

6.3 Recapitulation

The usefulness of the Montana University Coal Demand Study does not rest only with the actual numbers generated in the projections. Although we have compared the numbers generated in our study with those from other published studies, such comparisons have limited value in judging the accuracy and utility of the projections without a detailed explanation of the various methodologies and assumptions used. We believe our study will be useful for the following reasons:

1. It presents a systematic way to evaluate what will influence NGP coal development;

2. It indicates the key "swing" variables determining development; and

3. It established how, quantitatively, the level of development will vary if these variables change.

We feel that it is probably more important to know the key variables which affect the demand for NGP coal and the sensitivity of the level of development to those variables than it is to project an actual number. A systematic methodology with clearly detailed variables and assumptions promotes confidence in projections. In addition, if the sensitivity of the level of development to changes in the key variables is know, then future changes in political and economic conditions cannot easily render the projections invalid. These changes would simply shift the projected level of development in a quantitatively determined way. Our current "most likely" projection may not be valid several years from now, but knowing the sensitivity of the key variables, one could generate a "most likely" projection based on the new economic and political factors.

In conclusion we stress that it is not the numbers generated by a particular projection that are really important, but rather a knowledge of how these numbers would change as conditions change that is of critical importance in energy policy planning.